Energy Technology Innovation Policy Research Group

Putting It All Together: The Real World of Fully Integrated CCS Projects

By Craig A. Hart

HARVARD Kennedy School

Belfer Center for Science and International Affairs

July 2011

Discussion Paper #2011-06
Energy Technology Innovation Policy Discussion Paper Series

Belfer Center for Science and International Affairs
Harvard Kennedy School
79 JFK Street
Cambridge, MA 02138
Fax: (617) 495-8963
Email: belfer_center@harvard.edu
Website: http://belfercenter.org

Putting It All Together: The Real World of Fully Integrated CCS Projects

A Study of Legal, Regulatory and Financial Barriers in Phase III of the U.S. Department of Energy Regional Carbon Sequestration Partnerships Program

Craig A. Hart*

Energy Technology Innovation Policy
Belfer Center for Science and International Affairs
Harvard Kennedy School, Harvard University
79 John F. Kennedy Street
Cambridge, MA 02138
USA

Belfer Center Discussion Paper 2011-06
July 2011

*Craig Hart is an attorney practicing in the fields of project finance and carbon management. He holds a Ph.D. from the Massachusetts Institute of Technology and a J.D. from the University of California at Berkeley.

CITATION

This paper may be cited as: Hart, Craig A., "Putting It All Together: The Real World of Fully Integrated CCS Projects." Discussion Paper 2011-06, Cambridge, Mass.: Belfer Center for Science and International Affairs, June 2011.

Comments are welcome and may be directed to Craig A. Hart, craighart@alum.mit.edu. This paper is available at www.belfercenter.org/energy.

DISCLAIMER

Energy Technology Innovation Policy (ETIP)

The overarching objective of the Energy Technology Innovation Policy (ETIP) research group is to determine and then seek to promote adoption of effective strategies for developing and deploying cleaner and more efficient energy technologies, primarily in three of the biggest energy-consuming nations in the world: the United States, China, and India. These three countries have enormous influence on local, regional, and global environmental conditions through their energy production and consumption.

ETIP researchers seek to identify and promote strategies that these countries can pursue, separately and collaboratively, for accelerating the development and deployment of advanced energy options that can reduce conventional air pollution, minimize future greenhouse-gas emissions, reduce dependence on oil, facilitate poverty alleviation, and promote economic development. ETIP's focus on three crucial countries rather than only one not only multiplies directly our leverage on the world scale and facilitates the pursuit of cooperative efforts, but also allows for the development of new insights from comparisons and contrasts among conditions and strategies in the three cases.

ACKNOWLEDGEMENTS

The U.S. Department of Energy's Regional Carbon Sequestration Partnerships and their commercial partners generously gave their time to be interviewed on several occasions and to review preliminary drafts of this study. The efforts of partnership directors and their staffs, with the support of the Department of Energy, drive the Regional Carbon Sequestration Partnerships program. The following representatives of the partnerships participated in this study: Lee Spangler of the University of Montana (Big Sky Carbon Sequestration Partnership), Robert Finley of the Illinois State Geological Survey (Midwest Geological Sequestration Consortium), David Ball of Battelle Memorial Institute (Midwest Regional Carbon Sequestration Partnership), Ed Steadman of the University of North Dakota (Plains CO_2 Reduction Partnership), Jerry Hill of the Southern States Energy Board (Southeast Regional Carbon Sequestration Partnership), Brian McPherson of the University of Utah (Southwest Regional Partnership on Carbon Sequestration), Elizabeth Burton of Lawrence Livermore National Laboratory and Larry Myer of Leonardo Technologies and retired WESTCARB Technical Director (West Coast Regional Carbon Sequestration Partnership).

I am grateful to Henry Lee and Nathaniel Logar of Harvard University's John F. Kennedy School of Government, Kipp Coddington of Mowrey Meezan Coddington Cloud LLP and Diane Oh for their review and comments on earlier drafts of this study. Amanda Swanson of the Kennedy School assisted in preparing the manuscript for publication.

This study was supported by a grant from the Energy Technology Innovation Policy research group of the John F. Kennedy School of Government at Harvard University.

ABSTRACT

This study examines the legal, regulatory and financial issues encountered in nine planned commercial-scale carbon capture and sequestration (CCS) research, development and demonstration (RD&D) projects under Phase III of the U.S. Department of Energy's Regional Carbon Sequestration Partnerships (RCSP) Program. In Phase III of the RCSP, financial issues dominated the outcomes in these projects, directly causing termination of three of the projects and contributing to termination in two others. Long-term liability and lack of coordination among regulatory authorities also posed significant barriers.

TABLE OF CONTENTS

I. The U.S. DOE Regional Carbon Sequestration Partnerships Program

The Regional Carbon Sequestration Partnerships (RCSP) program of the U.S. Department of Energy (DOE) is the United States' leading effort to assess the performance, cost and risks of geologic carbon capture and sequestration (CCS) over a broad range of geologic conditions in order to assess its feasibility at commercial scale.[1] The program is organized as seven regional consortiums, each led by a university or national laboratory supported by industry partners, that are tasked with conducting actual CCS projects within their region.[2] The DOE launched the RCSP to develop the infrastructure and knowledge base needed to commercialize carbon sequestration technologies that will capture 90% of carbon dioxide (CO_2) with less than a 10% increase in the cost of energy, and achieve 99% storage permanence.

The RCSP program comprises three phases: (I) characterization of national CO_2 storage potential in deep oil-, gas-, coal-, and saline-bearing formations, (II) twenty-five geologic sequestration research, development, and demonstration (RD&D) test injection projects to validate that different geologic formations have the injectivity, containment, and storage effectiveness necessary for long-term sequestration, plus eleven terrestrial sequestration projects,[3] and (III) nine commercial-scale geologic sequestration projects to demonstrate the engineering and scientific processes and to validate the long-term safe storage of CO_2 in several major geologic formations capable of storing emissions generated from major point sources on a cost-effective basis.[4] The program has substantially completed Phases I and II, and is now implementing the Phase III projects. Appendix A lists the nine Phase III geologic sequestration projects surveyed in this study.

[1] Geologic carbon capture and sequestration involves the capture of carbon dioxide at a power plant or industrial facility, transport and ultimate injection of the carbon dioxide into subsurface geologic formations, principally saline formations, depleted oil and gas reservoirs and deep uneconomically mineable coal seams. CCS can potentially make a significant contribution to mitigating climate change by permanently storing carbon dioxide produced by coal- and natural gas-fired power plants and industrial facilities underground, as opposed to emitting it to the atmosphere.
[2] Although the RCSP uses the term "partnership" to describe the program, the organizational arrangements are collaborative relationships and not partnerships in the legal sense.
[3] The 25 Phase II geologic sequestration RD&D projects range in size from 43 tonnes in a single injection to approximately one million tonnes of carbon dioxide injected over a two to three year period.
[4] U.S. Department of Energy. http://www.fossil.energy.gov/programs/sequestration/partnerships/index.html (accessed on April 13, 2011).

The RCSP program was designed to provide real world experience on actual projects to researchers, regulators, project developers, investors, lenders, service providers and other stakeholders, and the projects were not intended to be challenge-free. Phase III of the RCSP is important because full integration is a critical step to validating CCS technology, driving down its costs, and diffusing it broadly. Putting all the pieces of a first-of-kind project together – technological, engineering, geological, financial, legal, and regulatory – involves significant challenges. Full-integration also necessitates a high degree of coordination among project stakeholders (e.g., investors, lenders, equipment suppliers, CO_2 sources, transportation providers, and pore space[5] owners), and requires sophisticated institutional arrangements among these parties to allocate project responsibilities and risks.

In Phase III, financial issues posed the most significant barrier and dominated the outcomes in these projects, directly causing termination of three of them and contributing to termination of another two projects. Liability for sequestration of CO_2 and lack of coordination among regulatory authorities also posed significant barriers. The financial, legal and regulatory challenges of fully integrated commercial-scale projects in Phase III are far more complex than encountered in the Phase II test injection projects that were the subject of an earlier study, and the need for policy support is more pressing.[6]

Phase III comprises nine planned projects that will inject and monitor between 1 to 5 million tonnes of CO_2 into geologic formations, eight of which are saline formations. Several of these facilities will continue to inject CO_2 after completion of the Phase III projects, in some cases up to 20 million tonnes of CO_2 will be injected. Phase III also demonstrates several leading capture technologies and applications. Three of the planned projects are commercial scale power plants (two post-combustion and one oxy-fuel), two are natural gas processing facilities, and two are ethanol production facilities. These seven projects are fully-integrated commercial facilities that would capture, transport, and inject CO_2 as part of their planned operation. The remaining two projects inject CO_2 from natural sources and therefore are not fully integrated operations because they do not involve industrial capture operations.

[5] "Pore space" is the spaces within a rock body that are unoccupied by solid material.
[6] See C. Hart (2009). "Advancing Carbon Sequestration Research in an Uncertain Legal and Regulatory Environment: A Study of Phase II of the DOE Regional Carbon Sequestration Partnerships Program." Cambridge, Massachusetts: John F. Kennedy School of Government, Harvard University.

The nine planned projects that are the subject of this study were identified by the regional partnerships and approved by the DOE for inclusion in Phase III of the RCSP. The DOE RCSP program provides financial support for the sequestration component of these projects. These projects must seek other financial support for the capture and transport aspects from commercial sources, and may seek other federal financial incentives to supplement the DOE grant for the sequestration component. During the period of this study, several of the original nine projects were terminated due to legal, financial, and regulatory barriers, and other projects have been or will be identified to take their place. This study evaluates Phase III of the RCSP based on the nine projects that were active as of mid-2009, tracking the outcomes through the end of 2010. It does not examine projects that replaced any of the original nine projects.

This study was completed during a period of ongoing federal government budget cuts in FY2011 that affected a variety of government programs that are relevant for CCS. More cuts are expected in the FY2012 budget, which could further impact CCS deployment. This study only analyzes federal government programs as of April 2011 and does not analyze potential future budget reductions or alternative means by which CCS might be funded if such budget reductions occur.

The paper is organized as follows. It first describes the study methodology. Next, it summarizes the CCS legal and regulatory framework prevailing in the United States as of April 2011 and analyzes legal barriers encountered across the surveyed projects. This analysis includes the review of two federal legislative proposals concerning transfer to the federal government of liability for long-term stewardship of CO_2 for qualifying projects (neither of which have been adopted at the time of writing). The study then turns to financial issues, reporting on financial barriers experienced by the Phase III projects and the federal financial incentives that could be available to CCS projects. It assesses the extent to which these incentives were available to, and actually assisted, Phase III projects. The paper concludes by recommending priorities for action by policymakers based on the experience of the Phase III projects in the areas of financial incentives, legal, and regulatory framework governing liability, and the adoption of liability transfer mechanisms.

II. Study Methodology

This study surveyed nine planned Phase III RCSP projects during the period of mid-2009 through 2010. Financial, legal, and regulatory considerations were tracked in order to assess the impact of these factors on resources (time and cost) and project design. Appendix A lists the nine Phase III projects surveyed in this study.

Interviews were conducted in person and by telephone with the leaders of all nine Phase III projects and commercial partners in four projects at several points during the mid-2009 through 2010 period. Because interviews were conducted while negotiations among research institutions, the federal government, and commercial partners were ongoing, information was collected with the understanding that it would be presented in summary form and that any project-specific information would be cleared by the project leader prior to publication. Project leaders and their commercial partners were given an opportunity to review and comment on this paper prior to publication. The questionnaire presented in Appendix B was used in these interviews.

As used in this study, the term "fully-integrated commercial project" refers to uniting CO_2 capture from an anthropogenic source, transportation, injection, and storage in a single project.

"Commercially viable" or "commercially sustainable" means the activities are financially sustainable based on the project's cash flows, taking into account government financial incentives and grants. Determination of commercial viability was based on the assessment of project leaders and their commercial partners.

Projects were classified as having an oil or gas component if they inject CO_2 into oil or gas bearing sites, including for enhanced oil recovery (EOR) or enhanced gas recovery (EGR) purposes, or if the sequestration site is owned by an oil or gas company. The involvement of an oil or gas company in a project would not qualify the project itself as having an oil or gas component.

The term "significant" is used to indicate those barriers that have or could consume substantial financial or personnel resources of research organizations or their commercial partners, to the point that they can delay or block progress of demonstration projects or research activities.

The term "CO_2-e" is the amount of CO_2 emitted that would cause the same radiative forcing as an emitted amount of a well-mixed greenhouse gas, or a mixture of well mixed greenhouse gases, all multiplied with their respective global warming potentials to take into account the differing times they remain in the atmosphere.

The term "tons" is used to denote short tons (2,000 pounds), and the term "tonnes" is used to denote metric tonnes (1,000 kilograms), depending upon the reporting convention used by the source, legislation, or regulation.

III. U.S. Federal and State Laws Governing CCS

Commercial adoption and diffusion of CCS requires a predictable legal and regulatory regime (e.g., pore space rights and liability, permitting, operating, and post-closure requirements), financial support to help cover the additional cost of CCS so that these projects are financially viable and commercially competitive, and a mechanism for allocating and sharing the risks associated with long-term CO_2 stewardship.

At the federal level, CCS is regulated by the U.S. Environmental Protection Agency (EPA) principally under the Clean Air Act and the Safe Drinking Water Act's (SDWA) Underground Injection Control (UIC) Program. A number of states have developed regulations for CO_2 injections that, together with the SDWA, define requirements for CCS projects in those states.

Property law defining ownership of pore space and liability for stewardship of CO_2 currently is not addressed by federal regulations governing CCS.[7] Property rights would ordinarily be governed by state law. A few states have defined property rights in pore space, addressed liability issues, and provided financial incentives. Of our nine Phase III projects, only two are located in states that have enacted any CCS legislation, and only one of these projects benefitted from a framework for sharing the risks associated with long-term liability.

This section summarizes the status of federal law and regulation, and selected state laws governing pore space ownership and long-term liability for CO_2 stewardship.

Federal Legal and Regulatory Framework

The federal government regulates the capture, transport, and geologic sequestration of CO_2 under various laws and regulations. With respect to capture of CO_2, the EPA regulates CO_2 emissions from certain major stationary sources under the Clean Air Act. Regulation of the safety of interstate pipelines is the responsibility of the Department of Transportation. The EPA regulates underground injections of CO_2 pursuant to its authority to protect drinking water supplies under the SDWA.[8] Federal law that could apply to CCS activities are described below,

[7] See In re Core Energy, LLC, UIC Appeal No. 07-02 (E.A.B., December 19, 2007).
[8] 42 U.S.C. § 300f et seq.

with the Clean Air Act and the SDWA described in detail as these are the primary means for regulating CCS at the federal level.

Clean Air Act

CCS may in the future be required as a "best available control technology" (BACT) for major stationary sources (and for major modifications to existing sources) of CO_2 under the Clean Air Act's Prevention of Significant Deterioration (PSD) permit and Title V permit programs. The background and an explanation of the EPA's regulation of greenhouse gases under the PSD and Title V programs are set forth here.

Following Massachusetts v. Environmental Protection Agency, 549 U.S. 497 (2007), in which the U.S. Supreme Court declared atmospheric emissions of CO_2 to be an "air pollutant" under the Clean Air Act, the EPA determined in late 2009 that the elevated atmospheric concentrations of six well-mixed greenhouse gases, taken in combination, endanger both public health and welfare ("the endangerment finding"), and that the combined emissions of these greenhouse gases from new motor vehicles cause and contribute to the air pollution that endangers public health and welfare.[9] The endangerment finding triggered EPA rulemaking for both mobile and stationary sources of greenhouse gas emissions under the Clean Air Act.[10]

For stationary sources, the EPA regulates greenhouse gas emissions (including CO_2) under the PSD permit and Title V permit programs. The PSD program is intended to protect public health and welfare and ensure that economic growth occurs in a manner consistent with the preservation of existing clean air resources. A PSD permit is required prior to construction of all new major sources or major modifications of existing sources for regulated pollutants regardless of whether the source is located in an area where the national ambient air quality standards (NAAQS), which define maximum permissible concentrations of regulated pollutants, are exceeded. The PSD program requires installation of BACT based on a multi-step analysis described further below.

[9] Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act; Final Rule. 74 Fed. Reg. 66496 (December 15, 2009).
[10] For greenhouse gas regulation of mobile sources, see Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule, 75 Fed. Reg. 25324 (May 15, 2010).

The Title V permit program provides an operating permit that is the mechanism for enforcement of all Clean Air Act requirements applicable to a source. While Title V permits generally do not establish new emissions limits, they consolidate requirements under the Clean Air Act, including applicable greenhouse gas requirements, into a comprehensive air permit. The operating permit thus contains conditions necessary to assure compliance with the Clean Air Act and a compliance plan, such as BACT requirements imposed pursuant to the PSD.

Under the Clean Air Act, a PSD permit is required for the construction (if the facility is new) or modification (if the facility is an existing source) of any "major emitting facility" defined as a facility that emits, or has the potential to emit, at least 250 tons per year of "any air pollutant", or 100 tons of one of 28 scheduled pollutants.[11] For existing facilities, a modification triggers the PSD requirement if it is a physical or operational change that "increases the amount" of any air pollutant emitted by the source.[12] Facilities subject to PSD would be required to use BACT for each pollutant emitted by the facility that is subject to regulation under the Clean Air Act.[13]

If the PSD requirements were applied to greenhouse gases based on the thresholds described above, the EPA would be required to regulate commercial and large residential emitters of greenhouse gases, vastly expanding regulation beyond large industrial emitters, as was intended by Congress. Accordingly, in May 2010, the EPA issued a "tailoring rule" restricting the applicability of the Clean Air Act's PSD and Title V operating permit programs with respect to greenhouse gases. Without this tailoring rule, application of the statutory thresholds would have imposed significant cost and burden on emitters, the EPA regional offices, and state regulators that issue Clean Air Act permits pursuant to delegation of authority from EPA regional offices, rendering the PSD program unadministrable.

The tailoring rule introduced the PSD requirements in phases. Starting on January 2, 2011, the EPA limited the PSD requirement to apply BACT for greenhouse gas emissions to those sources that are required to obtain a PSD permit due to increases in non-greenhouse gas pollutant emissions provided the facility has the potential to emit new or increased greenhouse gas emissions equal to or exceeding 75,000 CO_2-e tons per year. For the Title V program, only

[11] 42 U.S.C. § 7475(a), § 7479(1).
[12] 42 U.S.C. § 7479(1), § 7411(a)(4).
[13] 42 U.S.C. § 7475(a).

existing sources with, or new sources obtaining, Title V permits for non-greenhouse gas pollutants will be required to address greenhouse gas emissions during this first phase. Beginning on June 1, 2011, PSD and Title V requirements are extended to apply to greenhouse gas emissions if either: (1) for new or existing stationary sources, the PSD for greenhouse gases would have been required under the first phase, or (2) for new stationary sources, if the new facility's potential greenhouse gas emissions are equal to or greater than 100,000 tons CO_2-e and equal to or greater than the 100/250 tons PSD thresholds measured on a mass basis, or (3) for existing stationary sources, the existing source's potential total emissions for greenhouse gases is at least 100,000 CO_2-e tons per year, is at least 100/250 tons per year (depending on the source category) on a mass basis, and the net emissions increase from the modification would be at least 75,000 CO_2-e tons per year and greater than zero on a mass basis.

Starting June 1, 2011, Title V permit requirements would apply to those stationary sources for which the actual or potential emissions of greenhouse gases would be at least 100,000 CO_2-e tons per year and equal to or greater than 100 tons per year on a mass basis. In applying the rule, one calculates the sum of the CO_2-e on a tons per year basis of the six greenhouse gases (taking their global warming potential into account) and the sum of mass emissions on a tons per year basis of the six greenhouse gases. The EPA shall consider application of the PSD and Title V requirements to smaller sources by July 1, 2013. However in no event shall sources with a potential to emit less than 50,000 CO_2-e tons per year be subject to PSD or Title V permit requirements for greenhouse gas emissions before 2016.[14]

Under the Clean Air Act, each new source or modified emission unit subject to PSD is required to undergo a BACT review with respect to regulated air pollutants. Facilities subject to PSD for greenhouse gases will be required to limit their emissions based on BACT. The EPA provided guidance to state agencies setting permit requirements for greenhouse gas emitters to determine whether there are available and feasible technologies for controlling emissions.[15]

[14] Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule, 75 Fed. Reg. 31514 (June 3, 2010).
[15] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, PSD and Title V Permitting Guidance for Greenhouse Gases (November 2010 and March 2011) (available at http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf).

Under the guidance, permitting authorities make BACT determinations on a case-by-case basis, applying an established five-step process:

Step 1: Identify all available control technologies;
Step 2: Eliminate technically infeasible options;
Step 3: Evaluate and rank remaining control technologies;
Step 4: Evaluate cost, environmental and energy impacts of technologies; and
Step 5: Select the BACT and establish enforceable emission limits.

The EPA specifically identified CCS as a control technology that should be deemed "available" under Step 1 for large CO_2-emitting facilities, including fossil fuel-fired power plants and industrial facilities with high-purity CO_2 streams, although it recognized that technological and cost considerations may presently eliminate CCS as a candidate for BACT under Steps 2 and 4.

In addition to the PSD and Title V programs, the EPA's Mandatory Reporting Rule (MRR) under the Clean Air Act requires annual reporting of greenhouse gas emissions and CO_2 injections for both CCS and enhanced hydrocarbon recovery purposes. Subpart RR of the MRR requires reporting by facilities that inject CO_2 underground for geologic sequestration purposes, and subpart UU of the MRR requires reporting by all other facilities that inject CO_2 underground for any reason, including enhanced oil and gas recovery. Subpart RR and UU require facilities conducting geologic sequestration of CO_2 to develop and implement an EPA-approved site-specific monitoring, reporting and verification plan, and to report the amount of CO_2 sequestered using a mass balance approach. Subpart RR exempts certain research and development CO_2 injections, including the RCSP projects.[16] In addition, subpart PP imposes reporting requirements on facilities that capture CO_2 in order to supply it for commercial applications or to sequester or otherwise inject it underground. Reporting under these rules supplements the information reporting requirements under EPA's UIC program.

[16] Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide; Final Rule, 75 Fed. Reg. 75060 (December 1, 2010).

Transportation

The Department of Transportation (DOT) regulates the safety of transportation of CO_2, particularly the design, construction, operation, maintenance, and spill response planning of interstate CO_2 pipelines under the Hazardous Liquid Pipeline Act of 1979.[17] It is generally understood that siting of interstate CO_2 pipelines would not be subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) and that rate regulation of interstate CO_2 pipelines would not come under the authority of the FERC or the Surface Transportation Board.[18] Intrastate CO_2 pipelines would be regulated by the individual states.

Safe Drinking Water Act

The SDWA is currently the primary means for regulating CO_2 injections in the United States. The SDWA is intended to protect public drinking water supplies, including underground sources of drinking water. The EPA has established through its UIC regulations that underground sources of drinking water are underground aquifers with less than 10,000 milligrams per liter (mg/L) total dissolved solids (TDS) and which contain a sufficient quantity of ground water to supply a public water system.[19] The SDWA directs the EPA to establish regulations setting minimum requirements for state water quality. States with permitting programs that meet EPA requirements are eligible to retain primary enforcement responsibility.[20] The EPA administers the SDWA in states that do not adopt an approved UIC program. With the exception of 10 state programs administered by the EPA and 7 states that administer their programs jointly with the EPA,[21] all other states retain primary authority for administering the SDWA.

The SDWA requires applicants to obtain a permit to conduct an “underground injection” of substances under the UIC program. Permit applicants must demonstrate that the proposed

[17] 49 U.S.C. § 601 et seq.; 49 C.F.R. § 190, 195-199.
[18] But see Paul W. Parfomak, Peter Folger and Adam Vann, Carbon Dioxide (CO_2) Pipelines for Carbon Sequestration: Emerging Policy Issues, Congressional Research Service, July 31, 2009, for a discussion of how FERC or Surface Transportation Board jurisdiction could be extended to govern interstate CO_2 pipelines.
[19] 40 C.F.R. § 144.3.
[20] Section 1421(b) (3)(A) of the Act also provides that the EPA’s UIC regulations shall “permit or provide for consideration of varying geologic, hydrological, or historical conditions in different States and in different areas within a State.”
[21] U.S. Environmental Protection Agency, State UIC Programs, http://www.epa.gov/safewater/uic/primacy.html (accessed on August 7, 2008).

underground injection will not endanger drinking water sources.[22] The statute provides that underground injection endangers drinking water sources,

> [i]f such injection may result in the presence in underground water which supplies or can reasonably be expected to supply any public water system of any contaminant, and if the presence of such contaminant may result in such system's not complying with any national primary drinking water regulation or may otherwise adversely affect the health of persons.[23]

Although CO_2 that is injected into a properly sited and regulated formation should not come into contact with underground sources of drinking water, it could potentially cause acidification of drinking water, displace brine that could then come into contact with drinking water, or carry with it metals and other sediments that could contaminate drinking water.

UIC permits for underground injections are classified based on the type of injection. The class of permit typically depends on the activity associated with the well, and determines the specific regulatory requirements that the well operator will be subject to. Classes II and VI are candidates for commercial CO_2 injection wells and Class V can be used for research and development-related CO_2 injections:

- Class I injection wells are used to dispose of hazardous waste, non-hazardous industrial waste, municipal wastewater, and deep radioactive waste.[24]
- Class II injection wells are used for injections of fluids for disposal that are associated with oil and natural gas activities and injections for EOR or EGR.
- Class III injection wells inject fluids for mineral extraction.
- Class IV injection wells are used for hazardous or radioactive waste within a quarter mile of, into or above, potential underground drinking water sources.[25]
- Class V covers injections that are not covered by the other classifications, including experimental wells.
- Class VI covers CO_2 injections for CCS purposes.[26]

[22] 42 U.S.C. § 300h(b)(1)(B).
[23] 42 U.S.C. § 300h(d)(2).
[24] There are no known radioactive waste disposal wells operating in the United States. See http://www.epa.gov/ogwdw000/uic/wells_class1.html#what_is (accessed October 12, 2008).
[25] In 1984, the EPA banned the use of Class IV injection wells for disposal of hazardous or radioactive waste. These wells may now only be operated as part of an EPA- or state-authorized ground water clean-up action.

Class VI is the primary UIC category for permanent geological sequestration of CO_2 streams associated with commercial CCS. Class VI imposes the following requirements:

• Extensive geologic site characterization to ensure that sequestration wells are appropriately sited in areas with a suitable geologic system comprised of a sufficient injection zone and a confining zone free of transmissive faults or fractures, and identification and characterization of additional (secondary) confinement zones to impede vertical fluid movement;

• Injection at depths below the lowermost underground source of drinking water, unless a waiver is obtained from the agency;

• Operating procedures including injection pressure limits not to exceed 90% of the fracture pressure of an injection zone, maintaining annulus pressure greater than that of the injection zone, and installation of surface automatic shut-off devices for onshore wells and down-hole shut-off devices for offshore wells;

• Robust well construction design (surface and long string casing, tubing and packer) with injectant-compatible cement and other materials to maintain well integrity over the life of the sequestration project and prevent CO_2 movement into unintended zones;

• Re-evaluation of the area of review around the injection well at least every 5 years to incorporate monitoring and operational data, using computational models, and to verify that the CO_2 is moving as predicted in the subsurface;

• Extensive testing and monitoring plan, including testing the mechanical integrity of the injection well on a continuous basis internally and at least once a year externally; continuous monitoring of injection pressure, flow rate, injected volumes, and pressure on the annulus between the tubing and the long string casing; tracking the location of injected CO_2 and increased pressure levels; pressure fall-off tests; monitoring groundwater and geochemical changes in the subsurface; and other measures at the discretion of the agency such as surface air/soil gas monitoring to ensure protection of underground sources of drinking water;

• Well plugging and site closure regime that includes flushing the well with a buffer fluid, final internal and external mechanical integrity test, and emplacing injectant-resistant cement into the well to prevent fluid movement;

• A 50-year post-injection monitoring and site care period to track the location of the injected CO_2 and monitor subsurface pressures;

• Financial responsibility requirements to assure that funds will be available for well plugging, site care, closure, and emergency and remedial response;

• Emergency and remedial response plan; and

[26] 40 C.F.R. § 144.6.

• Reporting obligations.[27]

To qualify under Class VI, eligible CCS projects would be required to meet specific geologic requirements for the injection and confining zones (e.g., presence of cap rock, depth, absence of faults and fractures, pressure); to conduct analysis of the projected path of the injection plume; and to provide a detailed characterization of the injection formation in advance of permitting. The rule requires extensive pre-injection characterization and periodic post-injection monitoring for a 50-year default period or until the plume stabilizes. The EPA currently is in the process of preparing guidance under Class VI covering issues such as site selection and project management.[28]

Under the Class VI rule, the EPA retains availability of Class II injection well treatment for EOR/EGR activities provided these wells are still producing oil or gas and the EPA determines that there is not increased risk to underground sources of drinking water based on criteria specified in the regulations.[29] Existing wells that have been permitted under Classes I, II or V are grandfathered under the rule but are subject to additional Class VI conditions if they are used for permanent CO_2 sequestration purposes.

Worker Health and Safety

Worker health and safety at both the federal and state levels would also govern a CCS project. At the federal level, the Occupational Safety and Health Act (OSHA) requires employers to provide a workplace free from serious recognized hazards and to comply with occupational safety and health standards. The OSHA authorizes states to establish their own safety and health programs provided state requirements are at least as strict as federal standards. Pursuant to the OSHA, the National Institute for Occupational Safety and Health sets workplace exposure

[27] Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells; Final Rule. 75 Fed. Reg. 77230 (December 10, 2010).
[28] EPA final and proposed guidance documents are available at http://water.epa.gov/type/groundwater/uic/class6/gsguidedoc.cfm (accessed on April 13, 2011).
[29] 40 C.F.R. § 144.19.

guidelines for chemicals, including CO_2. OSHA regulations limit CO_2 exposure in the workplace to an average of less than 5,000 parts per million (0.5%) for a 40-hour workweek.[30]

Other Federal Regulations

Currently, no U.S. federal law or regulation classifies CO_2 as a "hazardous waste" or "hazardous substance", however the EPA noted in the SDWA Class VI rule that whether a CO_2 injection in a CCS project will trigger potential liability under the Resource Conservation and Recovery Act (RCRA) or the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) will depend on whether the CO_2 stream could contain other substances that are hazardous and could cause the CO_2 stream to be hazardous waste for purposes of the RCRA, or contain hazardous substances, or react to become a hazardous substance under the CERCLA.[31]

The RCRA establishes a ''cradle to grave'' regulatory scheme over certain ''solid wastes'' that are also ''hazardous wastes.'' The RCRA defines solid waste as, among other things, discarded material, including solid, liquid, semisolid, or contained gaseous material. To be considered a hazardous waste, a material must first be classified as a solid waste under the regulations,[32] and then determined to be hazardous. A solid waste is a hazardous waste if it exhibits any of four characteristics of a hazardous waste (ignitability, corrosivity, reactivity, or toxicity) or is specifically identified by the EPA as such. The EPA is exploring a possible conditional exemption from the RCRA requirements for hazardous CO_2 streams, in order to facilitate implementation of CCS while protecting human health and the environment.[33]

---

[30] Occupational Safety & Health Administration, Carbon Dioxide (Revised Sept. 20, 2001), *at* http://www.osha.gov/dts/chemicalsampling/data/CH_225400.html. Research on the impact of exposure levels of CO_2 on human health show that concentrations of approximately 5% for extended periods can cause adverse physiological effects. See Sally M. Benson, Robert Hepple, John Apps, Chin-Fu Tsang, and Marcelo Lippmann, Lessons Learned from Natural and Industrial Analogues for Storage of Carbon Dioxide in Deep Geological Formations (Lawrence Berkeley Nat'l Lab. Report LBNL-51170, 2002) *available at* http://repositories.cdlib.org/lbnl/LBNL-51170/.

[31] See U.S. Environmental Protection Agency, Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells; Final Rule, EPA-HQ-OW-2008-0390 FRL-9232-7, 75 Fed. Reg. 77230 at 77260 (December 10, 2010).

[32] 40 C.F.R. § 261.2.

[33] EPA RIN 2050-AG60, Notice of Proposed Rulemaking, Hazardous Waste Management Systems: Identification and Listing of Hazardous Waste: Carbon Dioxide (CO_2) Injectate in Geological Sequestration Activities (transmitted

That the CERCLA authorizes the EPA to clean up sites contaminated with hazardous substances and seek compensation from responsible parties or compel responsible parties to perform cleanups themselves, could also be interpreted by the EPA or a court in a judicial proceeding to apply to CCS activities. The CERCLA exempts from liability certain ''federally permitted releases."[34] The EPA noted in the Class VI rule that a federally permitted release "would include the permitted [CO_2] injectate stream as long as it is injected and behaves in accordance with the [Class VI] permit requirements" and that there are no releases from a permitted well outside the scope of the Class VI permit.

Other federal laws such as the Clean Water Act (governing surface waters), the Toxic Substances Control Act, the Pollution Prevention Act, the Endangered Species Act, or the National Historic Preservation Act (where sites contain landmarks or archeologically significant items) could also potentially be applicable to a CCS project.

State CCS Laws and Regulations

In the absence of comprehensive federal legislation, several states have enacted CCS legislation aimed at addressing legal and financial barriers. These laws include defining ownership rights to pore space, allocating liability, specifying requirements for monitoring, mitigation and verification of CO_2 sequestration sites, and providing financial incentives to local CCS activity.

State leadership in CCS has been significant where it has occurred. Interviews conducted during the Phase III study reveal that where state laws have been passed, they have influenced the selection of capture, transportation, and sequestration sites. The table below summarizes state actions governing CCS for selected issues. In addition to these, over a dozen other states are considering CCS legislation

to the Office of Management & Budget on March 22, 2011). The proposed rule remains pending at OMB as of April 13, 2011.

[34] 42 U.S.C. § 9601(10).

Table 1: Selected State CCS Laws

	Site Permit	Property Rights	State Liability Transfer Rule	Liability Fund
Illinois		●	●	
Kansas	●			●
Kentucky				
Louisiana	●	●	●	●
Mississippi				
Montana	●	●	●	●
North Dakota	●	●	●	●
Oklahoma	●	●		
Texas	●	●	●	●
Utah	●			
Washington	●			
West Virginia	●	●		
Wyoming	●	●	⊙	●

Notes: Property rights include specifying ownership of pore space or CO_2, clarifying potentially competing claims of mineral rights holders to pore space, and providing for the state to exercise eminent domain over sequestration sites.
"⊙" indicates rule that prohibits state acceptance of liability.

Wyoming, Louisiana, Montana, and North Dakota have all defined ownership of pore space. All these states have vested ownership of subsurface pore space in the surface owner, granting dominance to any mineral rights holders in both the surface and subsurface estate. Wyoming allows severance of pore space from the surface interest, whereas North Dakota expressly forbids severance, and Montana law is silent on the issue. Wyoming provides for unitization of pore space rights if 80% of the owners' consent. Several other states have defined ownership of CO_2 or provided eminent domain powers over sequestration sites.

Louisiana, Montana, and North Dakota have enacted legislation governing liability, in which liability first resides with the operator, and then is transferred to the state at some point after well closure, provided the operator complies with state requirements. Liability rests with the operator for 15 or more years after injection ends in Montana, and for 10 years in Louisiana and North Dakota, provided CO_2 is expected to be stable and meets closure requirements. Texas and Illinois have also developed legislation to address liability that is specific to the FutureGen project. The Texas legislation transfers liability to the state upon completion of injection.

Unlike other states, Wyoming has passed legislation expressly allocating liability to the operator indefinitely. Wyoming law prohibits the state from accepting liability for CO_2 injections. Although Wyoming law otherwise provides a comprehensive institutional framework supportive of CCS activities, the liability rule proves to be a strong disincentive for CCS projects in Wyoming as described later in this study.

Six states have created liability funds to cover the costs of monitoring, enforcement, and post-closure remediation. These funds do not relieve operators of liability for negligence during the operational phase. The funds are capitalized through fees paid by operators, generally on a volume of CO_2 injected basis.

IV. Legal and Regulatory Barriers

Of the nine Phase III projects, six projects reported significant legal issues that could consume substantial financial and personnel resources of research organizations and their commercial partners, potentially delaying or blocking projects and related research. Four projects reported significant legal issues involving liability for long-term stewardship of CO_2, although liability issues were present in all nine projects. Projects planning to sequester in sites owned by multiple land owners or owned by a commercial partner unwilling to accept liability for injected CO_2 faced barriers securing pore space rights. One project faced significant permitting issues. In Phase III as in Phase II, commercial partners expended substantial resources to assist the research organizations in resolving property rights and legal liability issues, and obtaining consents.

Table 2: Phase III Projects Reporting Significant Legal Issues

	Total Injection Volume in Tonnes		
	Up to 2 million	**2 to 3 million**	**5 million**
Number of Projects	5	2	2
Projects Reporting Significant Legal Barriers	3	2	1
Non-Oil/Gas-related Projects Reporting Significant Legal Barriers	2	1	0

Source: Author's interviews with Regional Carbon Sequestration Partnerships

Liability for CO_2 Stewardship

The scope of potential liabilities relating to long-term stewardship of CO_2 includes the following:

- Proper plugging and abandonment of wells;
- Long-term monitoring and management of sequestration sites;
- Remediation of sequestration sites;
- Regulatory liability, including loss of any carbon credits, due to CO_2 leakage;
- Loss of life or injury;
- Property damage (including subsurface property); and
- Environmental damage.

Long-term liabilities are distinct from ordinary operational liabilities of commercial firms conducting drilling, injection or providing other services. Ordinary operational liabilities have not posed barriers to Phase III projects.

In all of the planned nine Phase III projects, liability for CO_2 stewardship was an issue of negotiation. Five projects resolved liability issues because private parties accepted responsibility for sequestered CO_2. Of those five projects, in three instances an oil and gas industry commercial partner accepted liability, in one instance a company that supplies CO_2 to the oil and gas industry accepted liability, and in the final case an industrial partner that owned the sequestration site accepted responsibility. While assumption of liability in five out of the nine Phase III projects is encouraging, almost half of the projects had not resolved liability issues. At the time of writing, some projects are still negotiating liability issues, and although this study does not track replacement projects, liability issues are also posing barriers to securing replacement projects.

In two of the nine planned projects, liability would be determined by state law, but with very different liability rules – one transferring liability to the state after a period of years and the other prohibiting the state from accepting liability. Inability to resolve liability issues in the project located in the state that is prohibited from accepting liability contributed to the project's termination.

Table 3: Phase III Long-Term Liability Outcomes

Outcome	Phase II Projects	Phase III Projects
Liability Raised in Negotiation	9 of 14	9 of 9
Liability Not Raised in Negotiation	5	0
Liability Assumed by Project Party	6	5
Liability Assumed by Oil or Gas-affiliated Party	6	4*
Liability Being Negotiated – No Result Yet	2	3
State Law Liability Rule	0	2
Liability Contributed to Project Termination	1	1

N=14 for Phase II; N=9 for Phase III. Phase II data as of January 2009 (Hart, supra note 6).
*Three oil and gas commercial partners and one supplier of CO_2 to the oil and gas industry.
Source: Author's interviews with Regional Carbon Sequestration Partnerships

Acceptance of liability by commercial partners is an important factor in the design and implementation of the United States' national CCS RD&D program. The universities and national laboratories that serve as the lead research organizations are not appropriate parties to bear these liabilities and some are unable to accept such responsibility. Partnerships therefore sought partners who could bear these risks. As in Phase II, the need for commercial partners that would accept responsibility for CO_2 stewardship influenced project selection and design, favoring projects involving an oil and gas component as this industry regularly accepts liability for injection of CO_2 in EOR and EGR operations. Importantly, the liability issue could block power sector projects that are critical to development of CCS. In Phase II and III, no electricity generation commercial partner has yet to accept liability for sequestered CO_2.

Nor do private insurance markets currently offer a solution. Insurance was considered in all of the Phase III projects as a possible means to address liability issues, however none of the projects reported taking out a CCS-specific policy. Comprehensive insurance for long-term CO_2 stewardship is not yet available in the market, as described in the text box below.

The Potential Role of Private Insurance in CCS

Two private insurers have developed CCS-specific policies that provide limited coverage for CCS projects, but do not provide protection against long-term liabilities. One insurer offers a policy for the operational phase that covers liability arising from environmental pollution, CO_2 transportation, out of control wells, geomechanical events, and business interruption. The policy is similar to insurance for traditional oil and gas operations. A geological sequestration financial assurance policy is available that covers risks related to increased implementation costs, accelerated closure, and cost over-runs during the closure phase and for a limited period following closure.[35] This policy could potentially satisfy financial assurance requirements under the UIC program's Class VI regulations for CCS injections.

Neither of these policies insures against long-term liability for the CO_2 stewardship that has posed a barrier to CCS RD&D projects. These policies do not insure against property or casualty losses suffered by third parties as a result of CCS operations or CO_2 leakage. They both cover the operations phase, and the financial assurance policy covers only a limited period of the post-closure phase. These policies are subject to annual renewal, as is typical for most policies.

[35] Zurich (2009). Press Release (January 19, 2009). Available at http://www.businesswire.com/news/home/20090119005535/en/Zurich-creates-insurance-policies-support-green-house (accessed September 17, 2010); University College London, "Climate Change, Emission Trading and Financing", available at http://www.ucl.ac.uk/cclp/ccsfinancing-overview.php (accessed September 17, 2010).

While the contribution of industry partners to the Regional Carbon Sequestration Partnerships is crucial to the success of projects, the U.S. CCS RD&D program should not depend upon commercial firms accepting responsibility for liabilities that they are not required to undertake by law or that are not related to their core businesses. This approach puts these projects at risk. As CCS projects become larger by CO_2 volume, or seek to sequester CO_2 in saline formations without oil and gas activity in the vicinity, the inability to locate parties to accept liability could prevent projects from going forward and hamper national CCS research.

In order to promote diffusion of CCS at the scale and pace necessary to meaningfully contribute to addressing climate change, the federal government should provide a risk sharing mechanism for federally-funded CCS RD&D projects and first-of-a-kind CCS projects. Leaving liability transfer mechanisms solely to the states will result in incomplete coverage as demonstrated by the fact that only one of the Phase III projects was covered by a state risk sharing mechanism.

The earlier Phase II study urged the federal government to provide research organizations and organizations supporting small-scale RD&D with a limited shield from liability for CO_2 stewardship, coupled with limited indemnification for qualifying projects to protect and make whole property rights holders, parties granting consent to projects, and third parties adversely affected by CCS research.[36] While a limited liability shield and indemnification provision could help small-scale research, commercial-scale CCS RD&D projects require a different approach. Commercial scale projects will ultimately require a scalable insurance mechanism that combines private and public responsibility for risk. It should be designed to strengthen risk management by requiring project developers to bear certain risks, along with private insurers, and encourage the private sector to undertake CCS projects by government accepting responsibility for long-term stewardship of CO_2 injected in compliance with regulations and after proper well closure and stabilization of the CO_2 plume.

[36] The liability shield and indemnification provisions proposed for Phase II test injections would not protect parties against their own negligence or intentional misconduct, would be limited in scope to third party claims relating to long-term stewardship of CO_2 (not ordinary operating liability), and could be limited in various other ways based on safety and other prudential considerations. For further details of the proposal, see C. Hart (2009), supra note 6.

Proposed Federal Liability Regime

In recent years the Senate has considered two bills that would have provided liability coverage for CO_2 stewardship for a limited number of CCS projects. In mid 2009, the Senate Committee on Energy and Natural Resources marked up Senate Bill 1013 the "Department of Energy Carbon Capture Sequestration Program Amendments Act of 2009" to amend the Energy Policy Act of 2005[37] and would create a federally-backed CCS insurance scheme for up to nine large-scale demonstration projects sequestering over one million tons of CO_2 per year from industrial sources. The bill called for the project owner to continuously monitor the site in the post-injection closure and monitoring phase, to retain responsibility for the sequestration site during that phase, and to provide financial assurance undertakings for at least ten continuous years until the injection plume stabilizes and the DOE issues a certificate of closure. Qualifying projects would receive a broad federal indemnity against ''(A) bodily injury, sickness, disease, or death; (B) loss of or damage to property, or loss of use of property; or (C) injury to or destruction or loss of natural resources, including fish, wildlife, and drinking water supplies." The indemnity would not protect the insured against its own gross negligence or intentional misconduct. In exchange, the government would collect a fee from sequestration site operators that would be calculated based on the expected net present value of payments to be made by the government under the indemnity. The long-term liability provisions of S. 1013 were reintroduced in early 2011 by Sen. Bingaman (D-NM), chairman of the Senate Committee on Energy and Natural Resources.[38]

Senate Bill 3589 "Carbon Storage Stewardship Act," introduced by Sens. Voinovich (R-OH) and Rockefeller (D-WV) in July 2010, and thereafter referred to the Senate Committee on Energy and Natural Resources, would have provided much broader coverage. This bill provided two mechanisms that could have assisted the Phase III projects. First, the bill proposed a federal trust fund that would indemnify states that accept stewardship of CO_2 from projects that meet federal guidelines or, if no state accepts liability, indemnify a federal agency accepting stewardship responsibility. The bill would have covered all reasonable costs associated with accepting

[37] 42 U.S.C. §§ 16511-16514.

[38] See S. 699, the DOE CCS Program Amendments Act of 2011. It remains unclear if Sen. Bingaman (D-NM) will endeavor to mark up and thereafter move S. 699 as a stand-alone bill or include it in a broader energy bill that the Senate Committee on Energy and Natural Resources is endeavoring to introduce.

responsibility for CO_2 and covering costs of administration, monitoring, remediation and any civil claims for personal injury, property damage, trespass or nuisance, excluding claims for punitive damages or non-economic losses. The trust fund would be governed by an independent board with claims being adjudicated by administrative law judges, and funded by annual assessments imposed on sequestration site operators based on the amounts injected, calibrated for the risk profile of the particular project, and further adjusted periodically to ensure the fund's assets are proportionate to expected claims. For projects covered by the trust fund, issuance of a certificate of completion for storage would completely bar civil claims brought against owners of a facility, transporters and generators, and would bar civil claims against project operators except to the extent that the trust fund board determines the trust fund lacks the funds to pay such claims. Significantly, the bill provides coverage for RD&D projects without being subject to annual assessment, provided that they inject less than one million tons per year, inject for no more than 5 years, and pose de minimus risk. Also, the bill covers CO_2 injected for EOR or EGR purposes to the extent it is to comply with mandatory greenhouse gas reduction obligations under federal or state law.

In addition to the trust fund, Senate Bill 3589 would directly indemnify operators and owners of up to ten first mover CCS projects for remediation and any civil claims. Qualifying projects must be designed to inject one million tons of CO_2 per year by 2020 and must demonstrate the commercial application of integrated capture, injection, monitoring and long-term geologic storage. Owners and operators would be required to maintain financial protection for remediation and civil claims.

If either of these bills had been adopted, they could have facilitated the deployment of the first CCS projects in the United States. However, Senate Bill 3589 would have been much more helpful to the Phase III projects. As drafted, Senate Bill 1013 would have been too narrow to provide much help to the Phase III projects. Of the nine projects, only five would qualify based on the one million tons threshold, and of those five, two would fail to meet the industrial source requirement, and one would not be eligible because the sequestration site is in Canada, leaving only two RD&D projects that could be eligible for this scheme. Of those two eligible projects, both were terminated.

In contrast, Senate Bill 3589's trust fund mechanism would provide coverage irrespective of the size of the project and would relieve RD&D projects injecting less than one million tons per year of paying assessments. The trust fund arrangements encourage state efforts to accept stewardship by indemnifying them for doing so, while allowing federal agencies to directly accept this responsibility where no state liability transfer mechanism exists. Assuming all projects would meet other technical and financial requirements, Senate Bill 3589's trust fund mechanism would have provided coverage for all of the fully-integrated Phase III projects located in the United States, except projects conducted for EOR or EGR purposes because the injection would not be for the purpose of compliance with a greenhouse gas reduction regulatory program. Carving out EOR and EGR from the scope of coverage in this manner would probably not be detrimental to CCS RD&D efforts because project operators in EOR and EGR projects typically accept long-term liability for injected CO_2. Senate Bill 3589's provision for coverage of 10 first mover projects would have had the same effect as Senate Bill 1013's first mover program: only five would qualify based on the one million ton threshold, and of those five, two projects inject natural CO_2 and would therefore fail to meet the requirement that the project integrate capture. Finally, one would not be eligible because the sequestration site is in Canada, leaving only two RD&D projects that could be eligible, both of which were terminated.

These projects would also have been required to meet standards for measurement, reporting, and verification (MRV), purity of CO_2, and financial assurance. As these projects are among the most carefully selected and monitored in the world, all would presumably meet MRV requirements. Without implementing regulations, it is difficult to know which of these projects would meet the purity requirements. The financial assurance requirement would be difficult to meet for projects that are not commercially viable.

Property Rights

Among the four projects that were not terminated, the pore space rights already belonged to, or were secured by, a commercial project partner. Ongoing projects that have addressed these issues dealt with a single landowner or unitized rights holders for large areas, significantly reducing the burden of dealing with multiple parties. Of the four active projects, one involves Canadian provincial land, one involves land unitized for EOR with the injection rights owned by an EOR operator, one involves land unitized for oil extraction with the pore space rights expected to be secured, and one involves a sequestration site owned by the commercial partner. Only one project sought rights from neighboring landholders.

Among the five projects that were terminated, three of the projects involved multiple land owners, two of which involved unitized land, one project planned to sequester in land owned by a commercial partner who would not accept liability for CO_2, and one project had not identified its specific sequestration location. Failure to obtain property rights were not the cause of termination for any of these projects, however rights were not resolved in all of these cases at the time of termination, and there is evidence that projects that required rights from multiple holders would have faced protracted negotiations.

Three projects were planned in jurisdictions that clarified ownership of subsurface rights – one jurisdiction vested them in the state and two jurisdictions vested ownership of subsurface pore space in the surface owner. Two of these projects were terminated for reasons unrelated to property rights issues. Three projects were able to secure subsurface property rights in jurisdictions that had not passed any legislation on this issue. There is no clear evidence concerning whether states clarifying property rights affected Phase III project outcomes.

While simplified property ownership arrangements do not guarantee the success of a project, it is a strong indicator of the potential viability of a project. As suggested by the four active projects, seeking rights from a single large landowner or in a unitized field and sequestering in a site where there are oil and gas operations (especially involving EOR or EGR) may be preconditions for the success of CCS RD&D projects under the current legal and regulatory regime. In contrast, there is no evidence that clarification of subsurface property rights influences project outcomes.

Permits

Projects were surveyed prior to the adoption of the Class VI permit scheme and therefore this study does not report on Phase III experience with Class VI permits.

Only one project reported significant permitting issues. The project was terminated in part because applying for a Class V injection permit for experimental wells presented risk for the commercial partner who planned to extract hydrocarbons from the sequestration site and would otherwise seek a Class II permit for oil and gas-related injections.

Other Phase III projects reported that the time associated with preparation and agency review of SDWA UIC permit applications caused project delays. Projects also acknowledged that the permitting process involves greater complexity if more than one regulator's approval is required, especially where there is lack of coordination among government agencies.

As in Phase II, interviews revealed that decisions concerning the class of UIC permit were tied to the type of activity most closely associated with the injection (e.g., EOR/EGR) and the recommendations of commercial partners and the government agencies issuing the injection permits. Accordingly, two projects plan to apply as Class II permits for EOR/EGR injections and two projects planned to apply under Class I. In line with EPA guidance at the time, three projects proposed to apply under Class V for experimental wells.[39] One project would apply for either Class I or Class V. One of the projects will sequester in Canada and therefore is not subject to the SDWA UIC program.

Phase III interviews suggested that uncertainty in the permitting review process should be addressed, especially where multiple regulators are involved. Streamlined review procedures for small-scale research projects could be part of this approach as suggested in the earlier Phase II study, however better coordination among agencies appears to be the dominant concern for Phase III projects. Regulatory approvals should be integrated within a single agency or application to the greatest degree possible.

Role of Oil and Gas Industry in Phase III Projects

The oil and gas industry continues to play a significant role in Phase III projects. Six of the nine Phase III projects have an oil or gas component as part of their project design. Of those six projects, four considered EOR/EGR applications and at least one project planned to inject CO_2 for EOR/EGR purposes; three projects will inject in saline formations located within oil and gas fields and have oil and gas commercial partners; two projects are gas processing projects. An

[39] U.S. Environmental Protection Agency, UIC Program Guidance No. 83, "Using the Class V Experimental Technology Well Classification for Pilot Geologic Sequestration Projects" (March 1, 2007). Available at http://www.epa.gov/safewater/uic/pdfs/guide_uic_carbonsequestration_final-03-07.pdf.

additional project partnered with oil and gas companies although the project itself lacks any oil or gas component. Phase III follows a trend observed in the Phase II injection tests, in which almost three quarters of those projects were either EOR/EGR injections, or conducted on sites with oil and gas activities.[40]

The role of the oil and gas industry among Phase III projects demonstrated their potential critical role to support fully integrated projects. As in Phase II projects, oil and gas partners in Phase III projects were generally willing to accept liability for sequestered CO_2.[41] In Phase III, oil and gas industry firms accepted liability in three projects, a CO_2 supplier to the oil and gas industry accepted responsibility in one project, and a non-oil and gas commercial partner accepted responsibility for CO_2 stewardship in one project. In contrast, no power industry participant accepted these risks in Phases II and III.

In the Phase III projects with an oil or gas affiliation, the project leads credited its oil and gas partner for providing the following benefits:

- Accepted title to CO_2 and liability for long term storage of CO_2;
- Acquired pore space and/or assisted with acquiring legal rights to pore space;
- Provided access to existing pipelines or financed new pipelines;
- Provided geological assessment data for specific sites;
- Provided drilling and injection services;
- Provided source of CO_2 where original source became unavailable; and
- Enhanced public acceptance of project due to importance of oil and gas industry to local economy.

Oil and gas-related projects also received a higher percentage of cost share from their commercial partners. Based on the survey conducted as part of this study, projects with an oil and gas component achieved at least 50% cost share in all except two projects, compared to a cost share ratio of 20% in other projects.

[40] See C. Hart (2009), supra note 6.
[41] In Phase II, oil and gas-affiliated firms accepted stewardship risk in each of the six projects in which this issue was resolved based on a study completed in January 2009. See C. Hart (2009), supra note 6.

V. Financial and Commercial Aspects of Phase III Projects

Financial and commercial issues pose the predominant barriers to fully-integrated commercial scale CCS projects. The success of Phase III projects depend greatly on their commercial partners. In this section, we examine how the cost of CCS for different applications affects the design and outcomes of the Phase III projects. In the next section, we assess the extent to which federal incentives as currently designed address these barriers and find that they are often not sufficiently flexible or adequate to be of practical value to these projects.

Financial Barriers in Phase III Projects

CCS project economics are dictated by the source of CO_2 and the method of capture. Required capital expenditure for CCS vary significantly by industry, depending upon the concentration and purity of CO_2 produced by the facility and the equipment required for separation and treatment. Power, steel and cement facilities produce gas streams with low concentrations of CO_2 that require expensive gas treatment and separation equipment as well as dehydration and compression equipment, making these plants particularly expensive to equip for CCS. Adding CCS can increase the capital cost of these plants by hundreds of millions of dollars. In contrast, gas processing facilities and ammonia and ethanol production plants can produce highly concentrated streams of relatively pure CO_2 as part of their ordinary operations; thus these facilities require no significant additional equipment to treat and separate CO_2, and only require dehydration and compression equipment.[42] Due to their minimal equipment requirements, these CCS applications involve relatively modest increases in capital costs and the cost of production. For Phase III gas processing and ethanol projects injecting up to one million tons of CO_2 per year, the additional capital cost for dehydration and compression was estimated to range from \$10 million to \$15 million. As a result, these plants can produce CO_2 in the range of \$15 to \$30 per ton. In contrast, Phase III power plant projects estimated their cost to capture CO_2 to be upwards of a hundred dollars per ton.

[42] Natural gas processing plants must remove hydrogen sulfide from the CO_2 stream in order to inject it in saline formations (a cost they also would bear if they vented CO_2 into the atmosphere). Ammonia and ethanol plants produce nearly food-grade CO_2, although in the case of ethanol there could be some hydrogen sulfide and carryover from the fermentor.

Table 4 below presents estimated costs of CO_2 capture for various technologies and applications for nth-of-a-kind (NOAK) commercial plants based on several recent cost modeling studies. Table 4 illustrates the differences in projected costs among industries for mature CCS technologies at the point of widespread commercial adoption, as opposed to the costs of CO_2 capture for early stage facilities or Phase III projects. There is a great deal of uncertainty concerning the absolute numbers, however this paper cites these figures to show the relative costs of CCS among different types of applications. CCS is at an early stage of development and cost estimates vary widely, especially for initial demonstration power generation applications.[43] Estimates are highly sensitive to the assumptions used in the models, in particular the cost of steel, labor, and fuel, and vary based on plant size, location and company-specific variables.

Table 4: Representative Cost Estimates of CO_2 Capture by Industry

Facility	Cost of CO_2 Avoided ($/tonne CO_2) for Nth-of-a-Kind Plant	% Increase Commodity Cost with CCS
Natural Gas Separation and Processing	$19	1%
Fertilizer Production	$20	3%
Ethanol Production	$15 - $30	n/a
Integrated Steel Mill	$49	10% - 14%
Cement Production	$49	39% - 52%
Post-combustion Coal-Fired Power Plant	$57 - $78	61% - 76%
IGCC Power Plant	$63	37%
Oxy-Fuel Power Plant	$44-$57	53%-65%

Source: WorleyParsons and Schlumberger (2011), Economic Assessment of Carbon Capture and Storage Technologies: 2011 Update. Canberra, Australia: Global CCS Institute; WorleyParsons (2009), infra note 44; Mott MacDonald (2010), Global Technology Roadmap for CCS in Industry Sectoral Assessment: Cement; and author's interviews with industry participants.

[43] See, e.g., Mohammed Al-Juaied, and Adam Whitmore, "Realistic Cost of Carbon Capture" Discussion Paper 2009-08, Cambridge, Mass.: Belfer Center for Science and International Affairs, July 2009; and McKinsey & Company (2009). Carbon Capture & Storage: Assessing the Economics.

Among the Phase III projects, the two natural gas projects and the two ethanol projects involved lower and more predictable capital costs for the CCS component, and achieved higher success rates. The estimated cost of CO_2 capture for the Phase III natural gas and ethanol plants, as shown in Table 5 below, are in line with industry estimates in Table 4 above for NOAK plants, reflecting the relatively low incremental costs and technical complexity of equipping these facilities to capture CO_2. In contrast, the actual costs for Phase III power projects are significantly higher than the estimates in Table 4due in part to the early stage of technology development for power applications, the small volumes of CO_2 to be captured and greater complexity. The favorable economics and risk profile of natural gas and ethanol CCS projects are reflected by a lower termination rate compared to power projects.

Table 5: Selected Phase III Costs and Outcomes

Sector	Electricity	Natural Gas	Ethanol	Natural CO_2
Projects	3	2	2	2
Oil and Gas	3	2	1	1
Ongoing Projects	1	1	1	1
Termination Rate	67%	50%	50%	50%
CO_2 Capture Cost/ton	\$100 to \$200+	\$15 to \$30	\$15 to \$30	\$5
Average Private Sector Cost Share	\$92 million (60%)	\$82 million (67%)	\$20 million (23%)	\$16 million (29%)
Termination Cause	Technology (2) Financial	Commercial Permits	Opposition	Financial

Source: Author's interviews with Regional Carbon Sequestration Partnerships

Site selection and geologic assessment also represent significant cost barriers, and a critical stage at which point project developers evaluate the strength of the overall project before proceeding. Except for the cost of equipment for CO_2 capture, site selection and geologic assessment can be the single largest cost for a fully integrated project. The cost of site selection, including geologic assessment, can be as high as \$25 million to \$150 million or more, depending on geologic conditions.[44] For the Phase III projects, geologic assessment costs were at the lower end of the range, or below this range. These projects benefited from relationships with universities, national laboratories, and other state and federal institutions that made their expertise available, enabling them to complete assessments at lower cost. Federal grants supporting the RCSP projects can be used for site selection and assessment. Further, six of the Phase III projects conducted injection on sites with or in the vicinity of oil and gas operations, for which prior site characterization data was available. Of the five terminated Phase III projects, all were terminated before incurring significant costs for geologic assessment or drilling wells. In all cases, terminated projects reported their expenditures to be no greater than approximately $1 million per project, a portion of which was spent on geologic assessment.

Lack of supporting infrastructure for CCS, in particular the lack of a pipeline network, can add significant cost to projects. Hydrocarbon pipelines cost approximately $1 million to $2 million per mile to build in the United States, depending upon pipeline diameter, based on the 2005-2006 period.[45] Phase III projects generally selected sequestration sites within short distances from the capture facility and that have some pre-existing wells associated with oil and gas operations. For seven Phase III projects that had planned pipeline routes, the total distance of pipelines for all projects would be under 36 miles, with the shortest distance being a matter of yards. The short distances of these pipelines and the fact that all of them except possibly one would be intrastate precluded the need for more comprehensive transportation regulation.

In the face of significant cost barriers, strong financial incentives for conducting a CCS project are essential. With the exception of a project located in Canada, a jurisdiction with a carbon tax, none of the Phase III project developers are subject to any regulation that requires them to adopt CCS technology. Any financial incentives that are available would not be adequate to justify their undertaking these projects, except possibly natural gas and ethanol projects that qualify for the sequestration tax credit described in the next section. Enhanced oil or gas recovery was considered as a possible additional source of revenue in at least four projects. As described in

[44] WorleyParsons (2009). Strategic Analysis of the Global Status of Carbon Capture and Storage, Report 2: Economic Assessment of Carbon Capture and Storage Technologies. Canberra, Australia: Global CCS Institute.
[45] West Virginia University, U.S. Department of Energy Office of Fossil Energy, Lawrence Livermore National Laboratory, and China Shenhua Coal to Liquid and Chemical Co. Ltd. (2009). Carbon Capture and Sequestration Options for the Shenhua Direct Coal Liquefaction Plant: Final Pre-feasibility Study Report.

the text box below, enhanced oil recovery could provide significant financial incentives for CCS projects.

Enhanced Oil Recovery as a Driver for CCS

In enhanced oil recovery (EOR), CO_2 is injected into an oil reservoir in order to increase well pressure and reduce the viscosity of oil, thereby increasing production. Using conventional methods, approximately 20% to 40% of original oil in place will be recovered in a typical oil or gas field.[46] CO_2 floods can increase a field's production by 7% to 15% of original oil in place and extend the life of a field by 15-30 years.[47] One ton of CO_2 can lift anywhere from 1.5 to 6.5 barrels of oil, with an average of about 2.5 barrels.[48] Results vary by field characteristics: porosity, permeability, miscibility, gravity of the oil, operating depth, original and current reservoir pressure, location of oil in reservoir, operating temperature of reservoir, and geologic structure (e.g., dolomite, sandstone, carbonaceous).

Results also depend on operating decisions whether CO_2 injection is conducted solely to enhance oil production or also to achieve CO_2 sequestration. A portion of the CO_2 is separated and recovered from the lifted oil and re-injected into the reservoir; the remaining CO_2 is trapped in the reservoir. Through repeated cycles, essentially all of the CO_2 can be permanently sequestered, depending on operating decisions. By some estimates, one quarter to one third of a tonne of CO_2 per barrel of oil lifted is sequestered through EOR.[49] A similar process is followed for recovery of natural gas.

Terminated Projects: Time and Cost of Starting Over

Five of the nine projects surveyed were terminated and replaced (or seeking replacement) for various reasons ranging from financial viability of commercial partners, market conditions, risk associated with the capture technology, regulatory requirements, and community opposition. A termination rate of 50% or more is higher than desirable given that there are few possible candidate projects readily available relative to the desired number of pilot projects that are believed to be necessary to demonstrate CCS.

[46] Electric Power Research Institute (1999). Enhanced Oil Recovery Scoping Study. Palo Alto, California: EPRI.
[47] Moritis, G. (2001). "Future of EOR & IOR," Oil & Gas J., 99.20, 68-73.
[48] Martin, F.D. and J.J. Taber. (1992). "Carbon Dioxide Flooding," J. Petroleum Technology, 396-400.
[49] WorleyParsons (2009), supra note 44.

The diversity of reasons for terminating projects suggests that fully integrated projects are vulnerable to a wide range of risks. The broad range of causes is consistent with Phase III projects being large in scale, capital-intensive, complex technologically and in terms of implementation, and vulnerable to changing commercial conditions.

All of the project terminations in Phase III are related in some way to the commercial partners. The financial condition of the commercial partners and commercial conditions in their underlying business affected the viability of projects and resulted in three of the five terminations. Technology risks associated with CO_2 capture were sometimes driven by the commercial partner's decision to test new methods with the goal of proving and ultimately commercializing propriety technology. Regulatory issues, and in one case public opposition, increased project costs and delayed progress, leading to two projects being terminated for business reasons. Table 6 below summarizes the causes that contributed to termination of Phase III project.

Table 6: Project Termination Contributing Causes

Reason	Occurrence
Financial and Market Conditions	3
Capture Technology Risks	2
Permitting Requirements	1
Community Opposition	1

Source: Author's interviews with Regional Carbon Sequestration Partnerships.
Note: Some terminations involved more than one contributing cause.

A significant amount of both time and financial resources were invested in projects that were terminated. Based on interviews, the greatest impact of termination on the partnerships appears to be lost staff time and frustrated progress in their research agenda. Project leads were asked to quantify the time and money committed to terminated projects and efforts to identify replacement projects. In all cases in which projects were terminated, project leads estimated that losing a project set back their programs by between one to two years. Further, as a result, the partnerships lost commercial partners, and in some instances lost research staff. The financial implications of terminated projects were typically estimated to cost about $1 million per project; these costs were mitigated because projects were terminated prior to expenditures on advanced geologic assessment or drilling.

Dealing with financial issues also required a significant amount of time of the RCSP teams. Financial issues required more time of partnership staff than any function with the exception of research. Financial issues accounted for between 5% and 25% of staff time across the five partnerships that quantified their time allocations for this study, averaging about 10% of total staff time. Significantly, even partnerships that terminated projects due to financial and legal difficulties still allocated significant amounts of staff time to research, however these projects did not undertake the full scope of research or obtain experience implementing and operating a demonstration facility.

Table 7: Allocation of Time by Function

	Research	**Legal**	**Financial**	**Administration**	**Outreach**
Range	30% to 80%	2% to 15%	5% to 25%	5% to 25%	5% to 10%
Average	23%	5%	10%	7%	5%

Source: Author's interviews with Regional Carbon Sequestration Partnerships based on responses from five of the regional partnerships. Averages do not total to 100% because the average is calculated by function across projects.

VI. Federal Financial Support for Phase III Projects

The extent to which federal incentives that are generally available for CCS projects were available to, and accessed by, the eight Phase III projects located in the United States provide a strong indication of effectiveness of federal government support to overcoming financial barriers. We review the RCSP program grants, grants under the Clean Coal Power Initiative and the industrial CCS program, the CO_2 sequestration tax credit, the advanced coal project and gasification project tax credits, and federal loan guarantees for clean energy technologies. We also evaluate how the production of carbon credits could enhance the financial performance of these projects.

Financial support for CCS is crucial, especially for first-of-kind projects that are not yet commercially viable. Yet, few of the federal incentives intended for early stage CCS projects are available for the Phase III projects due primarily to eligibility requirements. The limited financial impact of these incentives among Phase III projects suggests that the federal government should adjust these incentive programs to provide more effective support to CCS RD&D projects.

Federal CCS Funding

The U.S. federal government began funding CCS research in 1997 with approximately $1 million in FY 1997. Spending increased to $283 million in FY2008 if FutureGen and other programs are counted.[50] CCS spending peaked as a result of appropriations in the American Recovery and Reinvestment Act of 2009 (ARRA), which provided $3.4 billion through FY2010 for fossil energy research and development. Of that amount, $1.52 billion was devoted to industrial carbon capture and energy efficiency improvement projects, $1 billion was provided for fossil energy research and development programs, and an additional $800 million was allocated to the DOE Clean Coal Power Initiative Round III which targets coal-based carbon capture and sequestration or reuse projects. The remaining $80 million was allocated for site characterization of potential geologic sequestration sites ($50 million), geologic sequestration training and research ($20 million), and unspecified program activities ($10 million). For FY2011 and

[50] Folger, Peter (2009). Carbon Capture and Sequestration. Washington, D.C.: Congressional Research Service.

FY2012, Congress is reducing federal spending for CCS and other energy technologies as a result of high government debt levels; any unused ARRA funds could be clawed back. [51]

RCSP Program Grants

The DOE awarded a total of $457.6 million to the seven RCSP partnerships, or on average $65 million per partnership, to conduct the Phase III projects. In addition to federal funding, each partnership is required to contribute at least 20% of total project costs from non-government sources. In practice, the portion of cost share has ranged between 20% and 86% of the total project costs for the nine projects surveyed.

RCSP grants cover operational costs of the RCSP program, and costs associated with the sequestration aspects of the research projects, specifically geologic assessment, permitting, drilling, well construction, injection, and monitoring. These funds do not cover the cost of capture equipment; the partnerships must find commercial partners who are willing to finance a capture facility or otherwise provide CO_2. Commercial parties can seek other government financial support, including from the incentives programs described below.

The cost share requirement is intended to ensure that projects funded with federal funds have potential to be commercially viable. Federal rules allow for contributions in kind to be counted, which makes it easier to meet the cost-share requirement. Overall, the 20% requirement did not appear to be a significant barrier.

The projects affiliated with the oil and gas industry enjoyed a higher percentage of private sector cost share. Projects with an oil or gas component had, with two exceptions, private cost shares of at least 50%. Projects without an oil or gas component had cost shares close to the 20% level. Power projects required a much higher private sector contribution to be feasible.

[51] Ongoing budget reductions stand as a separate impediment to CCS. House, Senate and White House negotiators reached an agreement on April 8, 2011 to fund the federal government for the remainder of FY 2011; that agreement generally provides across-the-board cuts for a variety of government programs that are relevant for CCS. Further cuts are expected to be made in the FY 2012 budget that Congress will take up later this year, which could impact CCS.

Clean Coal Power Initiative Round 3

The DOE's Clean Coal Power Initiative (CCPI) was originally designed to provide government co-financing for new coal technologies to reduce sulfur, nitrogen, and mercury emissions from power plants. Rounds 2 and 3 of the CCPI focused on ways to reduce greenhouse gas emissions by boosting the efficiency of coal-fired power plants and developing advanced coal technologies with CCS at commercial-scale. The ARRA made $1.4 billion available for Round 3. CCPI awards of $100 million to $350 million have been made to several projects.

Round 3 projects must achieve at least 50% CO_2 capture efficiency towards a target of 90% capture, with an increase in the cost of electricity of less than 10% for gasification systems and less than 35% for combustion and oxy-combustion systems. Projects must capture and sequester or put to beneficial use a minimum of 300,000 tons of CO_2 per year. To be eligible, power must account for at least 50% of the project's output, and coal must be used for at least 55% of feedstock. The CCPI requires a cost share of at least 50% of total project costs. The CCPI grant triggers a requirement for the administering federal agency to comply with the National Environmental Policy Act (NEPA), which could involve preparation of an environmental impact statement.

Of the eight U.S. Phase III projects, only three are power plants and thus eligible for the CCPI grant. Of those three, one was disqualified as proposed because it uses natural gas as its primary feedstock, but otherwise would have met most of the other requirements, except possibly the cost of electricity requirement due in part to the small size of the project.

The other two projects would meet the 300,000 tons per year sequestration threshold and the 50% minimum sequestration requirement. They both received Round 3 awards; however neither will ultimately be available to their Phase III projects. Southern Company was awarded $295 million in connection with the SECARB Plant Barry, Alabama project; the award was later withdrawn and therefore will not be available for the Phase III project. Basin Electric received a $100 million CCPI award, which could have been used to fund the capture component of the PCOR Williston Basin project. Since the Williston Basin project has been replaced, the CCPI funds may or may not support a Phase III project.

The 50% minimum cost share requirement is a significant barrier to utilizing CCPI awards. The private cost share can amount to hundreds of millions of dollars of additional cost for large CCS projects. Also, awards are conditional on the specific terms of the grant being negotiated between the DOE and the project developer. Failure to reach agreement results in withdrawal of the award. As of April 2011, five of the eighteen CCPI grants awarded in the three rounds had been withdrawn.

Industrial CCS Grants

The ARRA appropriated up to $1.3 billion in federal funds for large-scale industrial CCS projects, with a CO_2 capture rate of at least 75%. The grant targets projects that capture at least one million tons of CO_2 per year. It is available to all industrial sources, including cement, chemicals, refineries, steel and aluminum, manufacturing plants, and power plants using opportunity fuels (petroleum coke, municipal waste, etc.). Power producing facilities whose power output is greater than 50% of total production and that utilize 55% or more coal as a feedstock are ineligible. The program also allocated up to $100 million for projects that make beneficial use of CO_2. Grants require the private sector to bear at least 20% to 50% of total project costs, depending on the level of technology risk. The industrial CCS grant triggers a requirement for the administering federal agency to comply with the NEPA.

Of the eight U.S. Phase III projects, the one gas processing plant located in the United States and the two ethanol production projects qualify as industrial CCS applications. Only one of these projects would meet the one million tons per year sequestration target. Depending on operating decisions, two of the three projects could probably meet the grant's requirement that the facility achieve a capture rate of at least 75%. None of the Phase III projects received industrial CCS grants.

Secure Geologic Storage Tax Credit

The federal government provides a tax credit in the amount of $20 per metric ton of "qualified carbon dioxide" captured by the taxpayer at a qualified facility, and disposed of by the taxpayer in "secure geological storage," or $10 per metric ton for "qualified carbon dioxide" captured by the taxpayer at a qualified facility, and used by the taxpayer as a tertiary injectant in a qualified enhanced oil or natural gas recovery project, and then disposed of by the taxpayer in "secure geological storage." Qualifying projects must sequester at least 500,000 metric tons of anthropogenic CO_2 per year. The tax credit is subject to a 75 million ton limit.[52]

To qualify for the tax credit, the taxpayer must demonstrate that CO_2 will be disposed of in "secure geological storage." The definition of "secure geologic storage" focuses on adoption of measures to ensure that CO_2 does not escape into the atmosphere.

The owner of the capture facility is eligible for the credit. Access to the tax credit can be complicated where the owners of the capture facility, transport infrastructure, and sequestration site are different entities. The ownership structure of a project could affect the availability of the credit or limit its use, especially where the qualifying party lacks a tax liability to offset.

Of the eight Phase III projects that will sequester CO_2 in the United States, only six projects will inject anthropogenic CO_2, and of these only two projects would qualify for the credit based on the 500,000 ton per year threshold, assuming CO_2 from natural gas processing facilities is treated as anthropogenic CO_2 and the other conditions of the credit are satisfied. Of the two projects, one could qualify for the $20/ton credit for non-EOR/EGR sequestration and the other could qualify for the $10/ton EOR/EGR sequestration credit. For non-power sector projects that have lower costs of capture, the sequestration tax credit potentially provides significant incentive to undertake CCS.

Advanced Coal Project Credit and Gasification Project Tax Credit

Title XIII of the Energy Policy Act of 2005, as amended, provides investment tax credits of between 15% to 30% of the qualified investment cost of qualified power sector facilities or industrial gasification facilities that capture CO_2 that would otherwise be emitted into the atmosphere.[53] Aggregate tax credits of up to $3.15 billion are available under the program. Of this amount, tax credits of up to $2.55 billion are available for power generation technologies and $600 million in tax credits are available for industrial gasification projects. For power sector projects, $1.75 billion are available for advanced coal-based generation technologies projects and

[52] 26 U.S.C. § 45Q. See also Internal Revenue Service, "Credit for Carbon Dioxide Sequestration – Interim Guidance," Notice 2009-83, 2009-44 IRB 588 (October 8, 2009).
[53] 26 U.S.C. § 48A and § 48B.

up to $800 million for integrated gasification combined cycle (IGCC) projects. The taxpayer must elect between the power generation or industrial gasification tax credit, however it may use either with the secure geologic storage tax credit described above.

Qualified power projects must employ IGCC technology or other high-efficiency advanced combustion technology and must have at least 400 MW nameplate capacity, use coal for at least 75% of its feedstock, and capture at least 65% of CO_2 that would otherwise be emitted into the atmosphere (70% for reallocated credits). Non-IGCC advanced combustion technology must achieve thermal efficiencies of 40% for new facilities (35% for retrofit projects) and flue-gas emissions specifications for sulfur dioxide, nitrogen oxide, particulates, and mercury.

The industrial gasification tax credit is available to projects that use gasification technology related to chemicals, fertilizers, glass, steel, petroleum residues, forest products and agriculture applications, and transportation grade liquid fuels. Gasification technology is defined as any process which converts a solid or liquid product from coal, petroleum residue, biomass, or other materials which are recovered for their energy or feedstock value into a synthesis gas composed primarily of carbon monoxide and hydrogen for direct use or subsequent chemical or physical conversion that employ gasification technology. To qualify, industrial facilities must be financially viable and must use 90% of fuel consumption for production of chemical feedstock, liquid fuels or co-production of electricity. Of the $600 million in credits available to qualifying gasification projects, $250 million is allocated to projects that separate and sequester at least 75% of CO_2 that would otherwise be emitted into the atmosphere.

Of the Phase III projects, only seven projects capture anthropogenic CO_2 at facilities located in the United States; none of these Phase III projects would qualify for either investment tax credit. None of the three power projects would meet the 400 MW capacity threshold requirements. Only two of these projects would meet the requirement to use coal for at least 75% of their fuel input, as the oxy-combustion plant would be gas-fired. The three power projects would also be required to sequester 65% of CO_2 and meet the efficiency and flue-gas emissions performance specifications. Of the four non-power projects, none of them use gasification technology and therefore would not qualify for the industrial gasification project credit.

Loan Guarantees

Title XVII of Energy Policy Act of 2005 authorizes the Secretary of Energy to provide loan guarantees for up to 80% of total project costs for coal, nuclear, renewables, and other advanced technology projects that "avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases; and employ new or significantly improved technologies." The loan guarantee program is intended to support new and risky technologies that may not be able to access commercial loans. In 2009, the Secretary's loan guarantee authority for coal-based power generation and industrial gasification activities that incorporate CCS was increased to $6 billion, with an additional $2 billion for advanced coal gasification. The loan guarantee program is administered by application. The award of a loan guarantee triggers a requirement for the administering federal agency to comply with the NEPA.

Carbon sequestration practices and technologies are eligible under the loan guarantee program. Projects must demonstrate that they have a reasonable chance of repaying the loan within a 30-year period, effectively limiting the loan guarantee to those projects that would be commercially viable with the CCS component. The three power plant projects would need to demonstrate that they can meet specified flue-gas emissions levels for sulfur dioxide, mercury, nitrogen oxide, and particulates.

The loan guarantee program did not help Phase III projects for several reasons. For the power projects, the financial viability requirements are the most significant barrier to utilizing the loan guarantee program because these projects do not produce power on a commercially competitive basis. Of the two power projects that were terminated, neither was commercially viable. Two of the four commercial partners surveyed believed complying with the NEPA environmental impact assessment and reporting requirements as a condition of the guarantee outweighed its possible value. One commercial partner reported that high application costs, as much as $600,000, also deterred them from pursuing a loan guarantee. Two commercial partners planned to fund capital expenditures out of operating income and therefore would not require loan guarantees.

Carbon Credits

CCS carbon credits have only been traded in voluntary markets to date. In 2009, credits from geologic sequestration accounted for 3% (1.4 million tons CO_2-e) of all voluntary carbon transactions by volume, down from 5% the year prior.[54] CCS offsets transactions are traded in the over-the-counter market. Privately negotiated offsets have traded below $1 per tonne during the study period.[55]

The seven projects that proposed to inject anthropogenic CO_2 allocated rights to any carbon emissions reduction credits that might be produced to one or more project parties. However, none of those interviewed believed these credits would significantly alter the project's economics. Several parties expressed the view that, at current prices, credit revenues would not justify the investment of time and resources for developing the credits.

[54] Hamilton, Katherine, Milo Sjardin, Molly Peters-Stanley and Thomas Marcello (2010). State of the Voluntary Carbon Market 2010, Washington, D.C. and New York New York: Ecosystems Marketplace and Bloomberg New Energy Finance.
[55] Chicago Climate Exchange, Over the Counter Report (September 14, 2010).

Table 8: Summary of Federal CCS Financial Incentives

	CCPI Round 3	Industrial CCS Grant	Sequestration Credit	Advanced Coal and Gasification Project Credits	Loan Guarantee
Type	Grant	Grant	Tax Credit	Tax Credit	Guarantee
Award Amounts	Up to $1.4 billion available. No minimum or maximum limits for individual awards	10-12 grants of $500,000 to $3 million and 4-6 grants of $50 million to $400 million	$10/ton (EOR) $20/ton Up to 75 million tons	$2.55 billion for power; $600 million for gasification projects	Up to 80% of project cost
Technology or Application	Power output of at least 50%	Industrial CO_2 sources	Anthropogenic CO_2 sources	IGCC, advanced coal combustion generation, gasification	Coal, nuclear, renewables and advanced technologies
Fuel	At least 55% coal. Other solid fuels up to 45%	Any with limits on coal-fired power		At least 75% coal for power projects	
Capture, Efficiency, Environmental Performance	50%-90% capture rate. Electricity cost increase of less than 10% for gasification and 35% for combustion systems	75% capture rate	"secure geologic storage" and CO_2 purity	For all power projects, at least 65% capture rate. For non-IGCC power, 40% plant efficiency and flue gas standards. Certain gasification credits require 75% capture rate.	Flue gas standards
Size Threshold or Target	Sequester 300,000 tons CO_2 per year	Target sequestration of 1 million tons CO_2 per year	Sequester 500,000 tons CO_2 per year	400 MW for power projects	
Financial	50% or more cost share	20% cost share for small awards; 50% for large awards		Gasification projects must be financially viable	Ability to repay loan in 30 years
NEPA	Yes	Yes	No	No	Yes
Phase III Eligible Projects	2	1	2	0	3 if financial test satisfied
Phase III Utilization	2 awarded 0 utilized	0	Unknown	0	0

Source: Author's research and survey of Regional Carbon Sequestration Partnerships.

VII. Lessons from Phase III of the RCSP

Several lessons from Phase III of the Regional Carbon Sequestration Partnerships program should inform policies to support national CCS RD&D efforts.

Financing issues are the paramount barrier to fully-integrated CCS projects. Of the nine planned Phase III projects, significant financial issues caused termination of three projects and contributed to termination of two other projects. Federal financial incentives to support CCS were generally inadequate or not available to projects due to restrictions on project size, technology, or fuel.

Liability for stewardship of CO_2 remains a significant barrier to advancing CCS RD&D research. Liability was at issue in all of the Phase III projects. It was successfully resolved in five cases because commercial partners accepted liability in these projects. Without these parties, government-supported research projects could not have gone forward. As projects become larger in scale, we can expect liability issues to be increasingly important. Without a policy addressing liability, CCS research efforts may be increasingly difficult to undertake due to liability issues.

Coordination among agencies responsible for permitting CCS projects would reduce the costs and time associated with progressing projects.

Flexible Financing Incentives

Many of the Phase III projects could not access federal incentives due to restrictions on technology, fuel or project size. In cases in which incentives could be accessed, the incentives were generally inadequate to bridge the financing gap between first-of-a-kind CCS projects and conventional facilities without CCS.

Financial incentives for CCS activities should be designed as flexibly as possible to promote innovation and broaden access. Requiring specific technologies or fuels favors certain technology providers and commodity producers, an approach which is not optimal if the goal is to achieve cost effective CCS. Policies should be technology and fuel neutral, providing financial incentives to any technology that meets performance criteria. Policies should set sequestration, environmental and economic performance goals, and allow technologies to compete freely for federal support.

Size requirements rendered many of the federal incentives unusable by the Phase III projects and should be reconsidered. Examples of this include the advanced coal credit's 400 MW requirement for power generation facilities, which none of the Phase III facilities could achieve. Aspirational requirements are of no practical value at CCS's current stage of development and can defeat the purpose of legislation to promote larger projects. As one of the partnership leaders put it, "we don't get to the larger projects until we get past these [Phase III] projects."

Private parties should be allowed to allocate financial incentives among themselves without restrictions that impede their ability to optimally structure relationships. Rigid policies that require use of incentives by certain parties, or exclude certain classes of entities, limit their use. Examples of these restrictions include a Phase III project that could not make use of tax credits because they are organized as a cooperative, which does not pay taxes, and the tax benefit could not be passed on to the members of the cooperative. The sequestration tax credit is usable only by the taxpayer that owns the capture facility, which could limit its use if the capture facility, transport infrastructure and sequestration site are owned by different parties.

Federal incentives are generally inadequate to make commercially unviable projects into commercially sustainable ones. The Section 45Q sequestration tax credit bridges up to $20/ton of a financial gap that ranges from approximately $15 to $30/ton for ethanol and gas processing facilities. For power generation, the financial gap is in excess of $100 per ton. For incentives that require the facility to be of a certain size and impose a cost share obligation, the cost share could amount to hundreds of millions of dollars, making the project untenable for a commercial partner.

Scalable Liability Transfer Mechanisms

Surveys of the Phase III projects demonstrate that liability related to sequestration of CO_2 poses barriers to CCS RD&D projects. Liability is at issue in all of the Phase III projects and was successfully resolved in five projects because commercial partners accepted liability.

Several states have adopted risk sharing mechanisms and liability funds for CCS, allowing the transfer of liability after well closure and plume stabilization for qualifying CCS projects. While these state liability programs are extremely important, failure of the federal government to take action on liability transfer mechanisms is likely to result in incomplete coverage as demonstrated by the fact that only one Phase III project is covered by a state risk sharing mechanism.

Two of the projects illustrate how the liability rules can influence outcomes. Two of the Phase III projects planned to sequester in states that have enacted CCS legislation governing liability: one project planned to sequester in Wyoming, and the other project planned to sequester in either North Dakota or Montana. The liability rules governing these two projects could not be more different. The Wyoming rule imposed liability indefinitely on the operator, whereas North Dakota and Montana transfer liability to the state after a period of years if the CO_2 is expected to be stable and meets closure requirements. All three states have liability funds to cover post-closure monitoring and verification costs. However the Wyoming fund does not cover remediation costs, which remain the responsibility of the operator. Both projects were terminated and sought replacement projects. The Wyoming liability rule, which was passed after the project was initiated and already placed on hold for other reasons, posed difficulties for that project and the inability to resolve liability questions ultimately contributed to its termination. In the North Dakota/Montana project, regulatory issues did not play any role in the project's termination and the replacement project will be sited in one of those two states in part because of the favorable liability rules.

If we are to promote rapid diffusion of CCS, the federal government should take steps in this area to provide liability risk sharing for critical RD&D projects and first-of-a-kind CCS projects. Industry-funded, government-backed or -organized risk management schemes have long been used to address risks in the oil and gas industry, for underground injection of waste and other substances, and in the nuclear power industry. Examples of industry-funded, government-organized risk management mechanisms include the U.S. Oil Pollution Act of 1990's Oil Spill Liability Trust Fund, the Texas Oil Field Cleanup Fund, and Alberta's Acid Gas Injection Orphan Well Fund. Like state CCS-related liability funds, the oil and gas industry schemes generally impose a volume-based fee on the private operator that is deposited in a public fund to cover costs of remediation.

A federal liability transfer mechanism such as the trust fund proposed in Senate Bill 3589 would significantly reduce the risks of the Phase III projects and advance diffusion of CCS. The federal risk transfer mechanism should be compatible with state liability transfer arrangements.

Like the RD&D projects themselves, the federal government's efforts in developing a risk transfer mechanism should promote the creation of a sustainable national risk sharing mechanism. Government policy should promote the development of competitive insurance markets for CCS that expand the scope of insurable risks and drive down the cost of insurance while pricing risk appropriately. DOE programs such as the RCSP already produce a number of public goods that facilitate further development of private insurance for CCS. These include conducting geologic assessment of specific sites and disseminating the data publicly,[56] developing and testing new technologies and methods for early detection and mitigation of leakage, and developing risk assessment models that can be adapted on a project-specific basis. A national risk transfer pilot program could further these efforts by providing an opportunity to test models, with the goal of spinning off a self-sustaining national public-private insurance scheme for addressing liability for CCS. A pilot program should be scalable to a range of project sizes and promote development of a private insurance market.

Streamlined Regulatory Procedures

The Phase II study suggested that streamlined provisions for permitting small-scale CCS research and test injections under the SDWA could help facilitate research and development efforts. In Phase III, the concern was not so much over the regulatory burden associated with permitting applications, but rather on the potential for different government agencies to exercise overlapping or competing jurisdiction over different aspects of projects. A related issue concerns the introduction of new requirements under Classes V and VI. Based on the study survey, which was conducted prior to adoption of the Class VI rules, uncertainty related to the Class V requirements contributed to the termination of one project.

[56] The DOE's NatCarb initiative, which links geological and emission databases from several regional centers into a single interactive mapping system, could play an important role in ensuring that these data are publicly available.

Phase III interviews suggested that uncertainty of outcome and uncertain duration of the permitting review process should be addressed, especially where multiple regulators are involved. Better coordination among regulatory agencies appears to be the dominant concern for larger projects.

Phase III Lessons for Future Policy

Phase III of the Regional Carbon Sequestration Partnerships program face financial, legal, and regulatory barriers that require action by policy makers. The learning from the practical experience gained in implementing Phase III projects should inform the priorities and the design of policies intended to support the scaling up of CCS in the United States.

Without accessible financial incentives and liability transfer mechanisms, Phase III and other early stage projects face increased potential for delay or cancellation, increased costs, and loss of staff time as project developers struggle to overcome the challenges presented by these projects.

With precious few potentially viable demonstration projects, we cannot afford termination rates of over 50% as experienced in Phase III. While leveraging private sector resources and capability is essential, our national CCS RD&D efforts should not depend so completely upon private third parties that have no obligation and little if any incentive to undertake these projects. If we are to succeed in developing CCS on the scale necessary, federally-funded CCS RD&D projects should be supported at each step at which they face significant barriers.

Appendix A: Phase III Projects Surveyed

RCSP	status	Title	Geological Formation	Depth (m, ft)	CO_2 Source	CO_2 Injection Volume (tonnes/year)	Total Injection Volume (tonnes)
BSCP	S	Large Volume Injection to Assess Commercial Scale Geological Sequestration in Saline Formations	Nugget Sandstone	3,353 m (11,000ft)	Helium and Natural Gas Processing Plant	1,000,000	2,700,000
MGSC	O	Illinois Basin – Decatur Project	Mt. Simon Sandstone, Illinois Basin	1,524-2,134m (5,00-7,000ft)	Ethanol Plant	365,000	1,000,000
MRCSP	R	Large Volume CO_2 Injection in Western Ohio	Mt. Simon Sandstone, Cincinatti Arch	914-1,097m (3,000-3,600ft)	Ethanol Plant	250,000	1,000,000
PCOR	R	Williston Basin CO_2 Sequestration EOR	Depleted oil fields in Williston Basin, carbonite rocks	3,658m (12,000ft)	Post Combustion Capture Facility	1,000,000	5,000,000
PCOR	O	Fort Nelson CO_2 Acid Gas Injection project	Sandstone in the Alberta Basin	1,524m (5,000ft)	Natural Gas Processing Plant	1,000,000	5,000,000
SECARB	O	Development Phase Saline Formation Demonstration – Cranfield	Lower Tuscaloosa Formation sandstones	3,200m (10,500ft)	Natural Source	1,000,000 for early test	1,500,000
SECARB	O	Development Phase Saline Formation Demonstration – Anthropogenic	Tuscaloosa Formation Massive Sand Unit	2,896m (9,500ft)	Post Combustion Capture Facility	100,000 to 250,000	At least 400,000
SWP	S	Farnham Dome Deep Saline Deployment	Deep Triassic, Jurassic, and Permian Age sandstones, Farnham Dome	1,524+m (5,000ft)	Natural Source	1,000,000	2,900,000
WESTCARB	R	Sequestration of CO_2 from Oxyfuel Combustion Unit, Kern County, CA	San Joaquin Basin sandstone formation	2,134+m (7,000ft)	Oxy-combustion Power Plant	250,000	1,000,000

Table source: Adapted from WorleyParsons (2010). Strategic Analysis of the Global Status of Carbon Capture and Storage, Report 4: "Status of Carbon Capture and Storage Projects Globally". Canberra, Australia: Global CCS Institute (based on US DOE NETL 2008 Carbon Sequestration Atlas of the United States and Canada).

Legend: O = Ongoing; R = Replaced; S = Seeking Replacement. Note: This list reflects projects as of end of 2009 as project substitutions have occurred due to terminations

Appendix B: Legal and Regulatory Survey Form

REGIONAL CARBON SEQUESTRATION PARTNERSHIP:			NAME OF SURVEY RESPONDENT:			
Project Description	Parties (Circle applicable)	Of the parties, which are private entities? (Circle applicable)	Has anyone requested Indemnity? (Circle applicable)	Has anyone refused to grant rights? (Circle applicable)	Indicate if you are seeking property rights from neighboring properties? If so, describe who, why and whether there are any barriers or difficulty in obtaining necessary rights.	Describe any difficulty experienced or anticipated to obtain government permits? (e.g., public opposition, cost, resources)
Location: Type of Formation: Tonnes CO_2: Site Area: Status of Project: EOR: Unitized: EIS Required?	Site Land Owner Site Subsurface Owner Site Mineral Lessee Site Water Rights Holder Drilling/ Injection Company	Site Land Owner Site Subsurface Owner Site Mineral Lessee Site Water Rights Holder Drilling/ Injection Company	Site Land Owner Site Subsurface Owner Site Mineral Lessee Site Water Rights Holder Drilling/ Injection Company	Site Land Owner Site Subsurface Owner Site Mineral Lessee Site Water Rights Holder Drilling/ Injection Company	Y/N: From who are you seeking? Adjacent Land Owner Adjacent Subsurface Owner Adjacent Site Mineral Lessee Adjacent Site Water Rights Why seeking consents? Barriers to obtaining consents?	
Has any rights holders sought compensation for their consent?						
Please describe any other barriers you have encountered in these projects:						
Percentage Time Consumed: Non-Research (Legal/Administrative) % Research (including characterization) %						

Belfer Center for Science and International Affairs
Harvard Kennedy School
79 JFK Street
Cambridge, MA 02138
Fax: (617) 495-8963
Email: belfer_center@harvard.edu
Website: http://belfercenter.org